STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 97-596

March 26, 2001

MAINE PUBLIC UTILITIES COMMISSION
Investigation of Stranded cost Recovery
Transmission and Distribution, Utility
Revenue Requirements, and Rate Design
Of Bangor Hydro-Electric Company

ORDER

WELCH, Chairman; NUGENT and DIAMOND, Commissioners

I. SUMMARY

By this Order, we reduce the core tariff transmission and distribution (T&D) rates by 0.8¢/kWh for the customers eligible to be served as large non-residential standard offer customers in Bangor Hydro-Electric's (BHE) service territory. We do so to mitigate the impact of significant increases to generation prices, whether from standard offer or competitive providers, that these customers must pay effective March 1, 2001. We do not change the T&D rates for the residential/small non-residential and medium non-residential standard offer customer classes. We mitigated the standard offer prices for the small and medium classes by directing BHE to enter into multi-year power supply contracts, and then levelizing the lower-priced out-year costs with the first year supply costs. Moreover, the financial condition of BHE is such that the Company cannot finance the costs of additional mitigation without incurring greater financial risk than we assumed for BHE in setting its cost of capital in last year's rate proceeding.

II. BACKGROUND

New standard offer arrangements became effective on March 1, 2001 for all customers in BHE's service territory. By orders on February 2, 2001 and February 15, 2001, we approved wholesale supply arrangements so that BHE could serve as standard offer provider for the residential/small non-residential and medium non-residential standard offer customer classes. The wholesale power supply arrangement provides BHE with approximately 80% of the expected energy needs of the small and medium classes. BHE must acquire the additional 20% of energy and ICAP requirements and ancillary electric products by way of future bilateral contracts or the spot market. The February 15 contract also provides BHE with energy to serve 60% of the expected standard offer load for the small and medium classes for the year beginning March 1, 2002, and 40% of the expected load for the year beginning March 1, 2003.

In setting prices, the Commission levelized the out-year contract supply prices (reducing the first year costs) and estimated the other 20% of energy costs as well as the cost of ICAP and ancillary electric products. The resulting standard offer price for the residential/small non-residential class of $7.3¢/kWh represents an increase of

19.6% compared to the previous standard offer price and a 7.7% increase in total electricity costs. The seasonally-differentiated standard offer prices for the medium non-residential class, which average $0.073/kWh ($0.08498/kWh for June through August and $0.06889/kWh September through May), represent a 19% increase compared to the previous standard offer prices, and a 9.6% increase in total electricity costs.

By order dated February 20, 2001, we approved a wholesale power supply contract so that BHE could serve as standard offer provider to the large non-residential standard offer customer class. By order on February 27, 2001, we set time-differentiated average standard offer prices for the large class of 7.744¢/kWh, effective on March 1, 2001. The standard offer prices represent a 29% increase over the previous standard offer prices, and an increase in total electricity costs for large standard offer customers of approximately 16%, on average.

In addition, several medium and large customers are served by competitive providers. Because of current market conditions, customers who are served under retail supply contracts that will soon terminate will likely face similar price increases in the retail competitive market.

Recognizing the significant impact of these generation price increases, on February 9, 2001, we invited comment from interested persons on whether the Commission should mitigate that impact. The Commission also sought comment on whether mitigation should occur by adjusting standard offer prices, T&D rates or some other method. The medium and large standard offer customer classes in CMP's service territory were subject to similar generation price increases from standard offer arrangements that ended on February 28, 2001. Accordingly, we sought comments in our standard offer proceeding, Docket No. 2000-808, as to how to treat customers of both Central Maine Power Company (CMP) and BHE.[1]

The Commission received comments from CMP, BHE, Maine Public Service Company (MPS), Enron Power Marketing, Inc. and Enron Energy Services, Inc. (Enron), Independent Energy Producers of Maine (IEPM), Competitive Energy Services (CES), Energy Atlantic (EA), the Office of the Public Advocate (OPA) and the Industrial Energy Consumer Group (IECG). The commenters generally agreed that mitigation, if it should occur at all, should be implemented through T&D rates and not standard offer prices.

The utilities generally opposed T&D rate reductions to mitigate generation prices on the ground that the asset sale gain accounts are needed to avoid future price increases due to stranded cost recovery. The utilities argued that these accounts should be used only for T&D matters and not to soften the impact of generation prices; restructuring was intended to separate generation from T&D services.

[1] We have incorporated the comments into this proceeding.

The suppliers generally agreed that, most importantly, the Commission should avoid mitigation of standard offer prices. As to T&D prices, the suppliers' views included opposition (IEPM), neutrality (EA), and support for using BHE's asset sale gain account to provide relief to T&D customers (Enron and CES). Suppliers were generally opposed to the creation of new deferrals of T&D costs to provide rate relief, fearing that the credit worthiness of the utilities could create problems similar to those experienced by California.

Customer representatives advocated lower T&D rates to mitigate the higher generation prices. The OPA proposed a T&D rate reduction of 1¢/kWh. The IECG advocated a 2¢/kWh reduction. In IECG's view, such a rate reduction would merely recognize a future stranded cost recovery reduction that will result when the entitlements to the utilities' non-divested assets are sold into the generation market effective March 1, 2002, pursuant to Chapter 307. Moreover, the IECG argued that as a matter of equity, the T&D rate reduction should be granted to non-core or special contract customers as well as core customers.

Upon review of the written comments, the Commission scheduled a hearing on rate mitigation issues for March 2, 2001. The T&D rate cases for CMP and BHE, Dockets Nos. 97-580 and 97-596 respectively, were reopened for the purpose of holding the hearing and considering whether T&D rates should be lowered to mitigate the impact of generation costs.[2] By scheduling the matter in T&D rate case dockets, the Commission adopted the general consensus of the commenters, and decided that price mitigation, if it were to occur at all, would be accomplished only by lowering T&D rates. The Commission also sought information from CMP and BHE on their projections for the amortization of the asset sale gain account and the recovery of their stranded costs.

Representatives from CMP, BHE, OPA, IECG, and IEPM participated at the hearing. Generally, the parties advocated positions that were consistent with their written comments. The IECG modified its request for T&D rate mitigation from 2¢/kWh to 1¢/kWh.

III. DECISION

Rate stability of electricity prices has long been a factor in our ratemaking decisions. Rate stability means the avoidance of substantial rate changes, particularly rate increases. *Investigation of Central Maine Power Company Stranded Costs, T&D Revenue Requirements and Rate Design,* Docket No. 97-580 at 114-115 (March 19, 1999). For purposes of implementing T&D rates for BHE, effective with the beginning of retail access, we were guided by a "no-losers" principle. This principle meant that no customer should experience a rate increase with the implementation of T&D rates on

[2] Because the price increases in MPS's service territory were significantly less, the Commission did not consider mitigation of MPS's rates.

March 1, 2000.[3] For purposes of deciding whether "rates" would increase on March 1, 2000, we considered both generation costs and T&D rates. Even though, effective March 1, 2000, generation service became non-utility, deregulated service, we used projected generation service costs to assure ourselves that overall rates would not increase on March 1, 2000. *BHE Phase I Megacase Order*, Docket No. 97-596 (Nov. 24, 1999), *BHE Phase II Megacase Order*, Docket 97-596 (Feb. 29, 2000).

Even though generation costs are no longer regulated, it is clear that the post-March 1, 2001 generation price increases fall within a zone that can be described as "rate shock." If generation prices were still regulated, we likely would have "phased in" increases of this magnitude. *See Investigation into Central Maine Power Company Ratepayer Complaints,* Docket No. 92-078 (Aug. 5, 1992) (Commission imposed 8% rate stability cap for rate design changes rolled back 4%); *Maine Public Service Company,* Docket 84-80 (July 14, 1986) (Commission approved stipulation that "phased" Seabrook costs into rates over 3 years).[4]

Moreover, the asset sale gain account that resulted from BHE's generation asset divestiture provides us with some flexibility to consider generation price shock when we exercise our judgment to determine the schedule by which we amortize the account. Unfortunately, the amount of BHE's asset sale account is not comparable to that of CMP. There is simply less value to offset BHE's future stranded costs recovery. Additionally, BHE faces a stranded cost revenue requirement increase in 2003 because of the expiration of the advantageous BHE-Unitil contract. Accordingly, we believe that prudence dictates that an 0.8¢/kWh price reduction for all of BHE customers must be rejected, even though we granted such relief to CMP's T&D ratepayers that are subject to similar generation price spikes. *Order*, Docket 97-580 (March 26, 2001).

An 0.8¢/kWh price reduction to all BHE T&D ratepayers would require a revenue reduction of approximately $11 million. BHE's asset sale gain account balance is currently approximately $20 million. If it were used to fund such a reduction now, stranded cost recovery would cause T&D rate increases by 2003.

Additionally, the increased available value amortization would cause adverse cash consequences to BHE. We agree with BHE that it would be inequitable to add this financing burden at this time. As mentioned above, we have already imposed a

[3] The sale of BHE's generation assets at greater than book value, which created the asset sale gain account, gave the Commission flexibility in designing T&D rates while implementing the "no-losers" principle.

[4] We recognize that the goal of "rate stability" may in some circumstances conflict with the desire to ensure that consumers receive accurate "price signals." As long as consumers are still paying generation costs stranded from pre-restructuring days, however, they are arguably receiving an artificially inflated price signal. Against that backdrop, we do not see a danger that the action we take today to temporarily mitigate prices will "distort" consumer behavior in some economically undesirable way.

financing obligation on BHE to pay for the year 1 power supply cost levelization. BHE forecasts the year 1 levelization requires it to finance $5 million.

The power supply cost levelization benefits the residential/small non-residential and medium non-residential classes. Thus, we have already mitigated the standard offer prices to some degree for BHE's small and medium customers using BHE's credit.[5] The Commission has not, however, mitigated the standard offer price impact to BHE's large non-residential customers. We directed BHE to purchase an essentially all-requirements power supply contract for the large class. *See* Order, Docket 2000-808 (Feb. 20, 2001). The lack of any relief from the "rate shock" of current generation prices for BHE's large customers causes us to grant some T&D rate relief to the large customers. In a companion order issued today in Docket 97-580, we lowered kWh charges to CMP's medium and large customers' core rates by 0.8¢/kWh. For similar reasons, we find that BHE's large customers should also receive the 0.8¢/kWh rate reduction over the period April 15, 2001 to February 28, 2002.[6] We will achieve the 0.8¢/kWh large customer price reduction by increasing the available value amortization. By restricting the T&D price reduction to large customers, approximately $1.5 million of additional available value is amortized between April 15, 2001 and February 28, 2002. Thus, we avoid the adverse future stranded cost rate consequences that would result if all BHE customers received the 0.8¢/kWh price reduction.

As we stated in the companion CMP Order, we will consider the fact that we permitted some of the asset sale gain account to be used for the benefit of large customers when we address stranded cost class allocations in the next stranded cost investigation.

The 0.8¢/kWh T&D price mitigation will not be applied to those ratepayers on special rate contracts. Some T&D special contract customers pay T&D rates based on pre-existing "bundled" contract rates. Such customers pay the same total rate regardless of the cost of generation service because the T&D rate is reduced if generation prices rise. Thus, the T&D rates of those customers have already been (or will be) mitigated. Special contract customers that do not have pre-existing bundled contract rates will be affected by increased generation costs. However, these customers have bargained for reduced T&D rates in return for maintaining a level of contribution to T&D costs. Because these customers have had the benefit of lower T&D

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[5] We also mitigated small and medium customers' standard offer prices by directing BHE to adopt a portfolio power supply strategy, rather than an all requirements approach.

[6] As stated in the CMP companion Order, the reduction should first offset kWh charges, and then demand charges, if necessary to realize the full benefit of the mitigation. However, no T&D rate element should become negative.

rates through contractual commitments,[7] we conclude that these customers should be held to the bargain they made with the utility. Moreover, many if not most of these contracts were negotiated based on the customers' assertions that, absent a special rate, they would find substitutes for all or part of the supply they received from BHE. We have no evidence here that the increase in electricity supply costs that these customers are now facing is not matched by increased costs for those substitutes; thus we cannot assume that, from a ratemaking perspective, further T&D price decreases (here in the form of mitigation) are warranted.[8]

Accordingly, we

O R D E R

That Bangor Hydro-Electric Company shall file rate schedules to implement the rate reduction as described in the body of this Order, to be effective for service rendered on or after April 15, 2001.

Dated at Augusta, Maine, this 26th day of March, 2001.

BY ORDER OF THE COMMISSION

Dennis L. Keschl
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Nugent
Diamond

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[7] We note that the contract rates for most of these customers will remain lower than the mitigated core rate.

[8] If the substantial increases in generation prices would cause customers to reduce or eliminate service from BHE, we would expect BHE to seek to maximize contribution by reconsidering the contracted T&D rates.

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S.A. § 9061 requires the Public Utilities Commission to give each party to an adjudicatory proceeding written notice of the party's rights to review or appeal of its decision made at the conclusion of the adjudicatory proceeding. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 1004 of the Commission's Rules of Practice and Procedure (65-407 C.M.R.110) within 20 days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within 30 days of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S.A. § 1320(1)-(4) and the Maine Rules of Civil Procedure, Rule 73, et seq.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S.A. § 1320(5).

Note: The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review or appeal.